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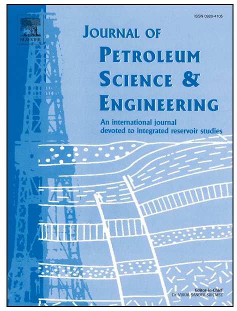

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Production Data Analysis in Gas Condensate Reservoirs Using Type Curves and the Equivalent Single Phase Approach

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Abstract

Most modern production data type curve (PDTC[1]) techniques, which are used in the estimation of reservoir and well productivity parameters such as permeability, drainage radius and skin, were originally developed with the assumption of Darcy flow (i.e. laminar flow, with pressure gradient proportional to the fluid superficial velocity, in accordance with Darcy's law) of a single-phase fluid. Two-phase conditions, e.g. in a gas condensate reservoir (GCR) operating below dewpoint pressure, introduce nonlinearities into the diffusivity equation, making the use of single-phase techniques questionable, and potentially producing erroneous parameter estimates. A common approach to linearizing the system is by the use of pseudovariables which account for the two-phase effects in addition to the pressure-dependence of fluid properties.

In this study, GCR production data generated using homogeneous fine-grid compositional simulation models, were first analysed using a well-known conventional (single-phase) modern PDTC technique, namely the Blasingame type curves for radial flow around a vertical well in a circular drainage area. The conventional techniques were then modified using an equivalent single phase concept, which was employed in the computation of two-phase pseudovariables for use with the single-phase PDTC. To compute these two-phase pseudovariables, pressure-saturation/k_r relationships are required. These were determined using a technique, which employs fluid component weight fractions and gas fractional flow of a fluid with constant fixed total composition. Sensitivities were conducted on reservoir fluid richness (maximum liquid dropout from 1% to 42%), relative permeability curves, degree of reservoir undersaturation and well operating pressures, to examine their impact on production decline response and subsequent conventional PDTC analysis, as well as their impact on the effectiveness of the equivalent single-phase based approach used in this study.

[1] PDTC = production data type curve; GCR = Gas Condensate Reservoirs; GTR = gas to total gas plus condensate flow rate; CCE = constant composition expansion, TCM = type curve match

The paper first highlights the impact of two-phase flow conditions in GCRs on conventional PDTC analysis, in terms of the quality of the type curve match (TCM) and estimates of permeability, drainage radius and skin. Then it is shown that, in GCR analysis where the impact of two-phase effects are important, significant improvements can be obtained, both in the quality of the TCM and subsequent parameter estimates, through the use of pseudovariables computed using equivalent single phase concepts. The results also identify conditions under which, depending on the fluid richness and/or the degree of undersaturation, two-phase effects, although present, may not significantly impact the quality of interpretation of long-term production data from GCRs, using conventional single-phase PDTC techniques.

Keywords: equivalent single phase; gas condensate reservoirs; production decline type curves; rate transient analysis; two-phase production data analysis.

1.0 Introduction

Traditional decline curve analysis, a branch of production data analysis, has been used, since its introduction by (Arps, 1945), for forecasting production performance and expected ultimate recovery (EUR) of wells and fields. Production data type curve (PDTC) analysis (a subset of rate transient analysis), in addition to production forecasting and EUR estimation, allows for the estimation of reservoir and well productivity parameters such as effective permeability (*k*), skin (*s*), average reservoir pressure and fluid-in-place.

Most modern PDTC techniques (Palacio and Blasingame, 1993, Agarwal et al., 1998), were developed on the assumption of single-phase Darcy flow, which implies laminar flow with pressure gradient proportional to the fluid superficial velocity, given that the resistance to flow (i.e. the ratio of fluid viscosity to matrix permeability, μ/k) remains constant, in accordance with Darcy's law. Under two-phase conditions resulting from retrograde condensation in gas condensate reservoirs (GCR), parameter estimates obtained using such techniques become unreliable, typically producing permeability estimates that are lower than the absolute permeability and in some cases, underestimating the drainage radius (r_e) as well.

A number of researchers have recently examined this problem using various production data analysis techniques – straight line analysis (Sureshjani and Gerami, 2011, Sureshjani et al., 2014, Behmanesh et al., 2015) and type curve analysis (Sarisittitham and Jamiolahmady, 2014, Sarvestani et al., 2016). Such work have focused on modifications of the pseudovariables employed in the data analysis to account for two-phase effects in GCRs.

In this study, we employed the Blasingame type curves (Palacio and Blasingame, 1993, Doublet et al., 1994) for radial flow around a vertical well in a bounded reservoir with a circular drainage area. To handle two-phase effects in GCRs, a pseudovariable modification based on the equivalent single phase concept (used by Saleh and Stewart (1992) for pressure transient analysis in GCRs, and by Jamiolahmady et al. (2006) in the development of a correlation for predicting near-wellbore gas condensate relative permeability), was used. The pressure-saturation/relative permeability relationships used in the computation of the modified pseudovariables were obtained using an approach which employs component weight fractions and gas to total (gas plus condensate) flow rate (Jamiolahmady et al., 2007), and which also assumes that near-wellbore two-phase steady state conditions are valid. This and other similar techniques are described in detail in Section 2.3.3.

This study demonstrates how the use of a combination of two-phase pseudopressures (Jones and Raghavan, 1988) and the equivalent phase material balance pseudotime, presented in detail in this paper, for PDTC analysis of data from GCRs can produce better quality of data analysis under a range of reservoir and well operating conditions. For this purpose, synthetic production data from fine-grid compositional simulation models were generated, which ensures that the prevailing conditions in the theory can be honoured where required, i.e. real data would be associated with impact of a large number of unknown parameters/effects.

This paper begins with a brief background of PDTC techniques, followed by a description of the equivalent single phase approach. Type curve analysis to determine k, r_e and s for twenty cases selected from the over fifty scenarios simulated are then presented, first using the conventional single-phase techniques, and then using the equivalent single phase approach. These are followed by discussions of the results and their potential implications for field applications.

2.0 Background/Theory

Arps (1945), presented the first systematic approach to decline curve analysis. His methods, which are still popular in industry today, involve fitting historical production rate data from the boundary dominated flow (BDF) regime to an empirically derived function (Eq. 1), on the basis of which future production performance of wells could be predicted.

$$q = \frac{q_i}{(1+bD_i t)^{\frac{1}{b}}} \tag{1}$$

Fetkovich (1980) later developed semi-analytical type curves, which combined analytically derived transient flow regime stems with Arps' empirically derived BDF hyperbolic decline stems, and laid the foundation for modern PDTC.

Modern PDTC, developed in the late 1980s to late 1990s are analytically-based, and make use of both rate and well flowing pressure data. Such techniques, like the Blasingame type curves (Palacio and Blasingame, 1993) which are used in this study, make use of a superposition time function to handle varying rate/varying pressure conditions, and pseudopressure functions to account for the pressure-dependence of fluid properties. Most of these PDTC techniques were however originally developed for analysis of single-phase flow.

Fraim and Wattenbarger (1988) presented some of the earliest studies on PDTC analysis for multiphase flow. Their work focused on solution-gas drive reservoirs for which they converted the mass flow rates of the individual phases into volumetric flow rates of a single-phase slightly compressible liquid for analysis using the Fetkovich type curves.

In this study, we focus on gas condensate reservoirs (GCR), for which the presence of two-phase flow conditions complicates the flow behaviour, by introducing severe nonlinearities in the diffusivity equation because not only the fluid properties are a strong function of pressure, but also mobility changes with saturation, pressure and velocity. Under such conditions, the use of single-phase techniques for the estimation of reservoir and well productivity parameters becomes questionable. Effective linearization should account for the two flowing phases present, in addition to the pressure dependence of fluid properties, to allow the liquid solutions to the diffusivity equation to be applied to the gas condensate system.

2.1 Single-Phase and Two-Phase Pseudopressures

The single-phase real gas pseudopressure function, Eq. 2, was defined by Al-Hussainy et al. (1966) to account for the strong pressure-dependence of gas properties for gas reservoir well test analysis and for gas reservoir calculations. For two-phase conditions in GCRs, Fussell (1973) put forward Eq. 3, based on two-phase "steady state" assumptions, similar in form to the single-phase pseudopressure integral (Eq. 2). Jones and Raghavan (1988), building on the work of Fussell (1973) , defined the two-phase pseudopressure sandface integral, Eq. 4, which they used in pressure transient analysis in GCR.

$$m(p) = 2\int_{p_b}^{p} \frac{p}{\mu(p)z(p)}dp \qquad \text{, where } P_b \text{ is a low base pressure} \qquad (2)$$

$$p_p = 2\int_{p_b}^{p} \left(\frac{k_{rg}}{\mu_g z_g}\right)\left(1 + \frac{V_o z_g}{V_g z_o}\right) p dp \qquad (3)$$

$$p_p = 2\int_{p_0}^{p}\left(\frac{k_{ro}}{\mu_o z_o}+\frac{k_{rg}}{\mu_g z_g}\right)pdp \qquad (4)$$

Fevang and Whitson (1996) defined a three-part multiphase pseudopressure function (Eq. 5) based on three flow regions (region 1, nearest to the wellbore, where both gas and condensate are present and mobile, region 2, where gas is mobile and condensate is immobile, and region 3, furthest from the wellbore, where only mobile gas is present), for use in gas condensate well deliverability calculations.

$$\Delta p_p = \int_{p_{wf}}^{p^*}\left(\frac{k_{rg}}{B_{dg}\mu_g}+\frac{k_{ro}}{B_o\mu_o}R_s\right)dp + \int_{p^*}^{p_{dew}}\frac{k_{rg}}{B_{dg}\mu_g}dp + k_{rg}(S_{wi})\int_{p_d}^{\bar{P}}\frac{1}{B_{dg}\mu_g}dp \qquad (5)$$

In the current study, for two-phase flow conditions, a two-zone radial composite model, like that employed by some researchers for well test analysis (Marhaendrajana et al., 1999, Raghavan et al., 1999, Xu and Lee, 1999, Osorio et al., 2005), and more recently by Sarisittitham and Jamiolahmady (2014) for production data analysis using type curves, was assumed. Such a model can be justified on the basis that critical condensate saturation can be quite low (i.e. close to but not zero), as has been demonstrated experimentally (Danesh et al., 1991, Henderson et al., 1998, Jamiolahmady et al., 2009).

In the outer zone of this model, where pressures are above the dewpoint pressure (p_{dew}), only gas is present and flows; while in the inner zone (closer to the wellbore), where pressure is below p_{dew}, both gas and condensate are present, and both phases are assumed to be mobile. Although this approach is different from the three-zone model employed in literature (Fevang and Whitson, 1996, Sureshjani and Gerami, 2011, Sarvestani et al., 2016) it should be noted that in our two-zone model, what may be considered as the transition zone (as per the three-zone model) is captured by the initially very low condensate mobility due to its very low relative permeability (k_{ro}) at low condensate saturations. On the basis of the two-zone model, the pseudopressure drop expressed by Eq. 6 was employed in the two-phase analysis. The pseudopressures were normalized using fluid properties at initial reservoir conditions (Meunier et al., 1987) prior to their use in the PDTC analysis.

$$\Delta p_p = 2\int_{p_{wf}}^{P_{dew}} \left(\frac{k_{ro}}{\mu_o z_o} + \frac{k_{rg}}{\mu_g z_g}\right) p dp + 2\int_{P_{dew}}^{P_i} \frac{p}{\mu(p) z(p)} dp \tag{6}$$

2.2 Single-Phase Material Balance Pseudotime (MBPT)

In their development of the material balance time function for use in variable rate reservoir limit testing, Blasingame and Lee (1986) presented the complete solution to the equation describing the behaviour of flowing well pressure (p_{wf}) as a function of time for a single well producing with variable rate in a bounded reservoir, Eq. 7a.

$$\frac{p_i - p_{wf}}{q_m} =$$

$$70.6\frac{B\mu}{kh}\ln\frac{4A}{e^{\gamma} C_A r_w^2} + 0.2339\frac{B}{\emptyset h c_t A}\frac{Q_m}{q_m} -$$

$$141.2\frac{B\mu}{kh}\left[\frac{2\sum_{j=1}^{m}(q_j - q_{j-1})\sum_{n=1}^{\infty}\frac{J_o\left(\frac{X_n r_w}{r_e}\right)}{{X_n}^2 {J_o}^2(X_n)} EXP\left(-{X_n}^2\pi(0.0002637)\frac{k}{\emptyset\mu c_t A}(t - t_{j-1})\right)}{q_m}\right] \tag{7a}$$

In order to employ this equation for straight line analysis of data from the boundary dominated "stabilized" flow (BDF) regime, the infinite series (i.e. the transient component) was assumed to be negligible, producing Eq. 7b. A plot of $\frac{\Delta p}{q_m}$ versus $\bar{t}$ (the material balance time) using data from the BDF regime yields a straight line with a slope from which the drainage area can be determined.

$$\frac{\Delta p}{q_m} = 70.6\frac{B\mu}{kh}\ln\frac{4A}{e^{\gamma} C_A r_w^2} + 0.2339\frac{B}{\emptyset h c_t A}\bar{t} \tag{7b}$$

$$\bar{t} = \frac{Q_m}{q_m} \tag{7c}$$

Blasingame and Lee (1988) later extended this approach to gas reservoirs using a modified gas flow equation. Palacio and Blasingame (1993), gave an analytical proof of the modified gas flow equation presented by Blasingame and Lee (1988), using material balance and pseudosteady state gas flow equations, and provided the most useful form of the flow equation for performing production data analysis under variable rate/variable pressure conditions, Eq. 8.

$$\frac{q_g}{(p_{pi}-p_{pwf})}b_{a,pss} = \frac{1}{1+\left(\frac{m_a}{b_{a,pss}}\right)\bar{t}_a} \quad (8)$$

In Eq. 8, $m_a = \frac{1}{Gc_{ti}}$, $b_{a,pss} = 141.2\frac{\mu_{gi}B_{gi}}{k_g h}\left[\frac{1}{2}\ln\left(\frac{4A}{e^{\gamma}C_A r_w^2}\right)\right]$, p_p are real gas pseudopressures, and $\bar{t}_a$ is the single-phase material balance pseudotime (MBPT) integral which is defined as:

$$\bar{t}_a = \frac{\mu_{gi}c_{ti}}{q_g}\int_0^t \frac{q_g}{\mu_g(\bar{p})c_t(\bar{p})}dt \quad (9)$$

The development of Eqs. 7b and 8 assumes stabilized BDF, making them strictly valid for post-transient flow. Palacio and Blasingame (1993) pointed out that Eq. 8 should trace the path of a harmonic decline on the Fetkovich type curves because it is identical to the Arps hyperbolic decline relation (i.e. Eq.1, with b = 1).

The MBPT integral and the Blasingame type curves used in this study are those presented by Palacio and Blasingame (1993) and Doublet et al. (1994), who built on earlier work by Blasingame and Lee (1986), Blasingame and Lee (1988), McCray (1990) and Blasingame et al. (1991). In this study, Eq. 8 was sometimes found to be inadequate for the analysis of GCR production data, therefore requiring modifications to account for two-phase conditions.

2.3 Equivalent-Phase Material Balance Pseudotime

Saleh and Stewart (1992), in their work on well test interpretation for GCR, made mention of a real condensate pseudotime function (Eq. 10). The viscosity term, μ_{tp}, in this equation was referred to as "total two-phase viscosity".

$$t_{a,tp} = (\mu c_t)_i \int_0^t \frac{dt}{\mu_{tp}c_t} \quad (10)$$

Recent work (Sureshjani and Gerami, 2011, Sureshjani et al., 2014, Sarvestani et al., 2016) have presented attempts to include two-phase considerations in pseudotime and material balance pseudotime (MBPT) functions for both straight line and type curve based production data analysis. Such attempts have however employed expressions that are relatively more involved than those used in this study.

Behmanesh et al. (2013) incorporated the equivalent single phase concept (Jamiolahmady et al., 2006, Jamiolahmady et al., 2009) into the pseudotime function, resulting in a formulation of two-phase pseudotime, similar to that of Saleh and Stewart (1992), which they used in straight line analysis of the transient linear flow regime of production data from hydraulically fractured shale gas condensate wells operating with constant p_{wf}. The equivalent phase concept had however not yet been employed in the MBPT integral for PDTC analysis. Initial attempts to employ the equivalent phase concept in modern PDTC in GCRs were briefly introduced by Johnson and Jamiolahmady (2016), and is now presented in detail in this paper.

In the present work, authors extend Eq. 9 and present an equivalent phase MBPT function (Eq. 11), which is computed using an equivalent phase viscosity and a total compressibility that account for the presence of the condensate phase. The fluid properties in the integral are evaluated at average reservoir pressure ($\bar{p}$), meaning that when $\bar{p} > p_{dew}$, the integral becomes the same as Eq. 9.

$$\bar{t}_{a,tp} = \frac{\mu_{gi} c_{gi}}{q_g} \int_0^t \frac{q_g}{\mu_{eqphase}(\bar{p}) c_{tot}(\bar{p})} dt \quad (11)$$

The appeal of this equivalent single-phase approach lies in the adaptation of the single-phase MBPT integral which, when used in combination with the two-phase pseudopressure, allows the single-phase type curves, and associated parameter estimation equations to be employed in the analysis of production data obtained under two-phase conditions.

2.3.1 Two-Phase Viscosity using the Equivalent Phase Concept

To obtain the equivalent-phase viscosity used in Eq. 11, the mass flow rate of the equivalent single phase was assumed to be equal to the sum of the mass flow rates (based on Darcy's equation) of the individual phases present, resulting in Eq. 12, from which the equivalent phase viscosity is obtained. Equation 12 is based on momentum balance, and assumes the presence of only gas and condensate, isothermal conditions, as well as negligible capillary pressure and gravity effects.

$$\frac{k.k_{rtp}A\rho_{tp}}{\mu_{tp}}\frac{dP}{dL} = \frac{k.k_{rg}A\rho_{g}}{\mu_{g}}\frac{dP}{dL} + \frac{k.k_{rl}\rho_{l}A}{\mu_{l}}\frac{dP}{dL} \quad (12)$$

If the relative permeability of the equivalent phase (k_{rtp}) is assumed to be 1, the two-phase viscosity presented by Saleh and Stewart (1992) is obtained. Saleh and Stewart (1992) mentioned that the use of the two-phase pseudopressure function incorporates the effects of two-phase flow, so that pressure transient analysis yields the absolute permeability and the equivalent single phase skin factor. As such, we consider that where two-phase pseudopressures are employed, it is justifiable to assume k_{rtp} = 1 in the definition of properties for the corresponding equivalent single-phase fluid. The two-phase density term (ρ_{tp}) can be defined as a gas fractional flow (GTR) weighting of the gas and condensate densities (Jamiolahmady et al., 2010), yielding the final form of the equivalent phase viscosity, Eq. 13, employed in this study.

$$\mu_{eqphase} = \frac{GTR.\rho_g + (1-GTR)\rho_l}{\frac{k_{rg}}{\mu_g}\rho_g + \frac{k_{rl}}{\mu_l}\rho_l} \quad (13)$$

ρ_l and ρ_g in Eq. 13 are oil and gas densities, k_{rl} and k_{rg} are base relative permeabilities of the liquid (condensate) and gas phases, respectively.

Most recently, in parallel and independent research by Behmanesh et al. (2017), the equivalent phase concept has been used for straight line analysis of data from the BDF regime in GCRs. In the work presented by Behmanesh et al. (2017), the equivalent phase viscosity defined by Saleh and Stewart (1992) was employed.

In the work presented here, the viscosity of the equivalent single phase has been defined on the basis of mass flow rates, as done by Saleh and Stewart (1992), and combined with equivalent phase density as defined by Jamiolahmady et al. (2010). It can be demonstrated that this definition of equivalent phase viscosity can be expressed simply as the inverse of total mobility, making it practically attractive because it is simple to evaluate and employ in the subsequent two-phase data analysis. Although the equivalent phase viscosity is not expected to have a physical meaning, its use in the MBPT integral is shown to produce consistent improvements in PDTC analysis under two-phase conditions.

2.3.2 Total Compressibility

Equation 14, 15 and 16 (Lake and Walsh, 2003) were used to compute the total compressibility, $c_{tot}(\bar{p})$ in Eq. 11.

$$c_{tot} = S_g c_g + S_w c_w + S_o c_o + c_f \tag{14}$$

$$c_o = \frac{1}{B_o}\left[\frac{-dB_o}{dp} + \frac{dR_s}{dp}\frac{(B_g - R_v B_o)}{(1 - R_s R_v)}\right] \tag{15}$$

$$c_g = \frac{1}{B_g}\left[\frac{-dB_g}{dp} + \frac{dR_v}{dp}\frac{(B_o - R_s B_g)}{(1 - R_s R_v)}\right] \tag{16}$$

Equations 15 and 16, which were used to calculate the condensate compressibility (c_o) and the gas compressibility (c_g), require the so-called modified/extended black oil parameters. These were obtained using the approach of Whitson and Torp (1981).

To compute the two-phase pseudovariables (i.e. Eqs. 6 and 11), a pressure versus saturation/k_r relationship is needed. A two-phase steady state based approach, much like those of O'Dell and Miller (1967) and Fetkovich et al. (1986), was used.

2.3.3 Pressure-Saturation Relationships for Two-Phase Analysis

O'Dell and Miller (1967), presented a two-phase steady state theory for performance prediction of single-well gas condensate systems, based on which Eq. 17 could be used for predicting pressure-saturation behaviour in the two-phase region around the wellbore, with the assumption that the composition of the produced wellstream is the same as the original single-phase reservoir fluid entering the two-phase region around the wellbore (i.e. initial reservoir pressure, p_i, remains significantly above p_{dew}).

$$\frac{k_{ro}}{k_{rg}} = \frac{V_o \mu_o}{V_g \mu_g} \quad (17)$$

In Equation 17, V_o and V_g are oil (condensate) and vapour (gas) volume fractions obtained from constant composition expansion (CCE) experiments. Later work provided theoretical proofs of this expression (Chopra and Carter, 1986, Jones and Raghavan, 1988). Eq. 18 (Jones and Raghavan, 1988), which includes the mole fractions of liquid (L) and vapour (V) in equilibrium at a given temperature and pressure, is the expression commonly seen in literature.

$$\frac{k_{ro}}{k_{rg}} = \frac{L \rho_g \mu_o}{V \rho_o \mu_g} \quad (18)$$

Fetkovich et al. (1986)also introduced a gas-oil relative permeability ratio (Eq. 19) for use in volatile oil reservoirs, which was employed in gas condensate deliverability studies by Fevang and Whitson (1996).

$$\frac{k_{rg}}{k_{ro}}(p) = \left(\frac{R_p - R_s}{1 - R_v R_p}\right) \frac{\mu_g B_{gd}}{\mu_o B_o} \quad (19)$$

The approach used in this study employs the weight fractions of the j^{th} component in the reservoir fluid mixture, z_j, expressed in Eq. 20 and the gas fractional flow (GTR), expressed in Eq. 21 (Jamiolahmady et al., 2007). At near wellbore conditions and when the two-phase steady state assumption is valid, total mass remains constant (i.e. z_j = constant), although there can be mass exchange between the gas and condensate phases.

$$z_j = \frac{\rho_g Q_g y_j + \rho_l Q_l x_j}{\rho_g Q_g + \rho_l Q_l} = constant \tag{20}$$

$$GTR = \frac{Q_g}{Q_g + Q_l} = \frac{\left[\frac{k_r}{\mu}\right]_g}{\left[\frac{k_r}{\mu}\right]_l + \left[\frac{k_r}{\mu}\right]_g} \tag{21}$$

In Eqs. 20 and 21, Q is the volumetric flow rate, x_j and y_j are the weight fractions of component j in the liquid phase (l) and the gas (g) phase, respectively, obtained from CCE of the original fluid at reservoir temperature.

Eqs. 20 and 21 can be combined to obtain Eq. 22, an expression of GTR in terms of x_j, y_j, z_j and the gas and condensate densities, which together with Eq. 21 and the gas condensate k_r curves and PVT data, allows pressure-saturation/k_r relationships to be established for two-phase analysis.

$$GTR = \frac{\rho_L x_j - \rho_L z_j}{\rho_g z_j - \rho_L z_j - \rho_g y_j + \rho_L x_j} \tag{22}$$

The pressure-saturation predictions obtained using the approach proposed in this work (i.e. Eqs. 21 and 22) were compared to those obtained using Eqs. 18 and 19, and found to produce the same results. However, the use of component weight fractions makes our approach more suited for compositional-based modelling studies.

2.4 Limitations of the Two-phase Steady State Assumption

Two-phase steady state pressure-saturation prediction methods are most reliable when most of the reservoir is still undersaturated, i.e. $\bar{p}$ is above the saturation pressure, and original fluid is still present in the reservoir (Fussell, 1973).

For pressure transient analysis in GCRs operating with p_{wf} below p_{dew}, Raghavan et al. (1999) pointed out that the k_r ratio of O'Dell and Miller (1967) works best when the pressure differentials $(p_i - p_{dew})$ or $(\bar{p} - p_{dew})$ and $(p_{dew} - p_{wf})$ are large (i.e. $\bar{p}$ is maintained above p_{dew}). They indicated that when this condition is violated, the predicted k_{ro} are higher and the predicted k_{rg} are lower than the actual values in the two-phase region around the wellbore, resulting in lower skin factor estimates obtained from two-phase analysis.

Estrada and Settari (2006) also noted that for $\bar{p} \leq p_{dew}$, well test analysis using Fussell's two-phase pseudopressure (Eq. 3) failed to accurately predict permeability thickness and skin – an observation they attributed to changes in the composition of the flowing fluid. They highlighted the point that Fussell's pseudopressure is applicable to well test analysis when little depletion has occurred, making it unreliable for long term deliverability estimation.

These observations all suggest that two-phase steady state based pseudovariables would potentially be inadequate for analysing depletion scenarios for long-term production data from GCRs, where $\bar{p}$ falls below p_{dew}, thereby violating the two-phase steady state constant composition assumption. While there have been extensive works (Jones and Raghavan, 1988, Jones et al., 1989, Raghavan et al., 1999, Gringarten et al., 2000, Estrada and Settari, 2006) on the impact of reservoir and well operating conditions on well test analysis of short-term data in GCRs using two-phase steady state assumptions, similar in-depth studies on long-term production data analysis using PDTC is relatively limited. This paper therefore examines this area.

3.0 Methodology

3.1 Reservoir Simulation Model

Production data for this study was generated using a commercially available finite difference based compositional reservoir simulator. A depletion drive operating mode was assumed. The reservoir was assumed to be of uniform thickness, with a closed outer boundary, and a homogeneous and isotropic matrix. Isothermal conditions (250ºF), the absence of an aquifer, negligible capillary pressure, negligible gravity effects, and zero interstitial water saturation were also assumed.

Table 1: Radial model

Parameter	Simulation Model Input
External reservoir radius	1242 ft (378.6 m) for cases 1 and 2, 1200 ft (365.8 m) for remaining cases
Well bore radius	0.35 ft (0.11m)
Interval thickness	70 ft (21.3 m) for cases 1 and 2, 100 ft (30.5 m) for remaining cases
Permeability	0.1 md
Skin	-5.16
Matrix Porosity	0.06
Rock compressibility	3 x 10^{-6} psi^{-1} at 4175 psia

The 1-dimensional radial model used (summarized in Table 1) was made up of 100 cylindrical grid cells, with logarithmically increasing grid-sizes to minimize numerical dispersion and approximation errors, and so ensure that rapid pressure and saturation changes in the near-wellbore regions were modelled as accurately as possible. The negative skin of a stimulated wellbore used in this radial model was implemented as an effective wellbore radius, as done by Fetkovich et al. (1987).

Initial reservoir conditions ranging from just saturated to severely undersaturated were considered. The simulations were run, at constant $p_{wf} < p_{dew}$, from initial conditions until an arbitrarily chosen minimum gas production rate (1 MSCF/day) was attained. The average reservoir pressure ($\bar{p}$) by the end of the production period for all cases was well below p_{dew}.

3.2 Fluid Model

Binary mixtures of methane and n-decane, shown in Table 2, with a wide range of fluid richness variations (maximum liquid dropout, MLDO, from 0.86% to 41.5%) were used. Fluid thermodynamic properties were computed using the modified 3-parameter Peng-Robinson equation of state and the Aasberg-Peterson viscosity correlation in a commercially available pressure/volume temperature (PVT) calculator.

Table 2: Gas condensate fluids.

	C1/C10 % mole ratios	Dewpoint Pressure (psia)	MLDO % (from CCE experiments)	MLDO Pressure (psia)
Very Lean 1	98/2	2441.2	0.86%	1000
Very Lean 2	97.5/2.5	2916.1	1.71%	1100
Lean	95/5	4259.8	7.39%	1600
Moderately Rich	90.5/9.5	5155.8	20.44%	3200

Rich	88.5/11.5	5288.5	28.01%	4300
Very Rich	86.5/13.5	5332.1	41.50%	5200

The RC1b k_r curves (Fig. 1) and TC k_r curves (Fig. 2), obtained from a database of gas condensate k_r of actual cores measured by the Heriot-Watt Gas Condensate Research Team, were used. A manually modified version of the RC1b k_r curves, with enhanced k_{ro} (incorporated into Fig. 1), was also employed in some of the simulation cases. It should be noted that these are base k_r curves. In other words, velocity-dependent permeability effects (Danesh et al., 1994, Henderson et al., 1997, Jamiolahmady et al., 2000), which cause reductions in effective permeability (i.e. inertia) with increasing flow velocity or enhancement in effective permeability under two-phase conditions with increasing velocity and/or decreasing interfacial tension (i.e. coupling), are ignored. These effects are known to be important in gas condensate reservoirs, however, in this study they were found to be less significant for long-term production decline response in the low permeability reservoir models employed.

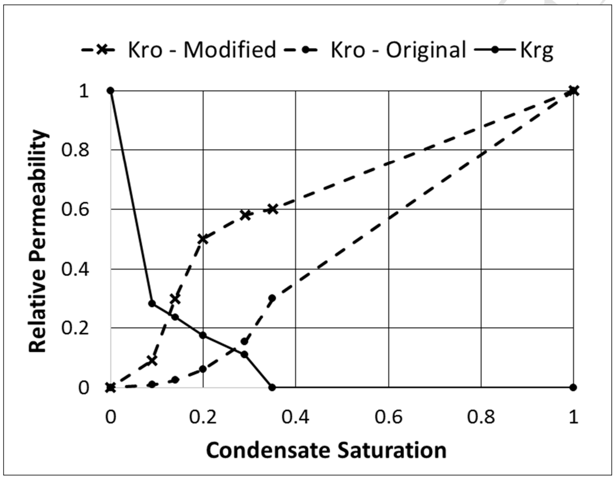

Fig. 1: RC1b & RC1b-Mod (Enhanced k_{ro}) gas-condensate relative permeability curves.

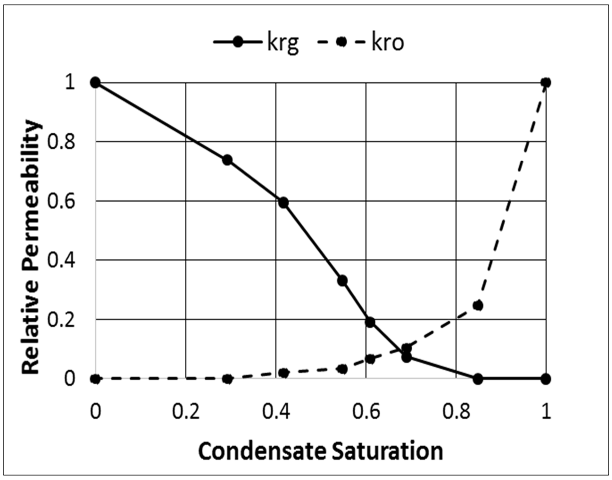

Fig. 2: TC gas-condensate relative permeability curves.

The equivalent phase viscosities (computed using Eq. 13) used in the two-phase analysis are shown in Fig.3 and Fig. 4 for the RC1b k_r curves, using a lean fluid (MLDO = 7.39%)

and a rich fluid (MLDO = 28.01%), respectively. Those computed using the TC k_r curves with the lean fluid and rich fluid are shown in Fig. 5 and Fig. 6, respectively.

It is noted that, for the lean fluids (Fig. 3 and Fig. 5), the equivalent phase viscosities lie between the oil and gas viscosities; however, for the rich fluid (Fig. 4 and Fig. 6), the equivalent phase viscosities generally exceed the oil viscosities. The equivalent phase viscosity is the inverse of the total system mobility, and represents an equivalent single phase fluid property for which k_r = 1. Hence, a significant decrease in the gas and condensate mobility and thereby that of the total system, must necessarily translate into a higher equivalent phase viscosity. As the total mobility improves, the computed viscosities also decrease. In other words, because the relative permeability of the equivalent phase is unity, at very low total mobilities, it is possible for the computed equivalent phase viscosity to exceed that of the most viscous phase present (in this case, that of the condensate). This is what is observed for the cases with rich fluid, which are associated with more significant reductions in total mobility.

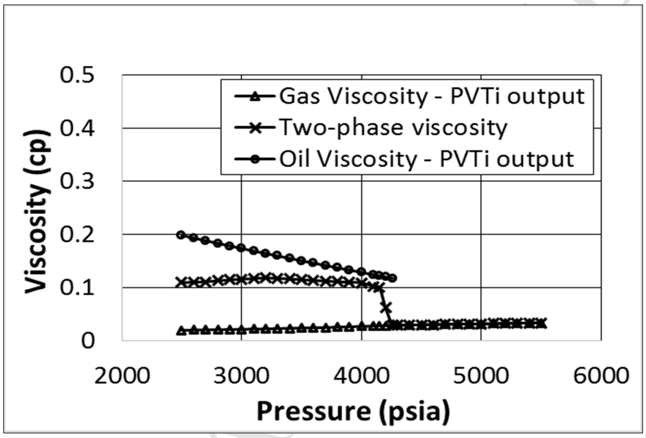

Fig. 3: Viscosity Computations – Lean Fluid, RC1b k_r Curves.

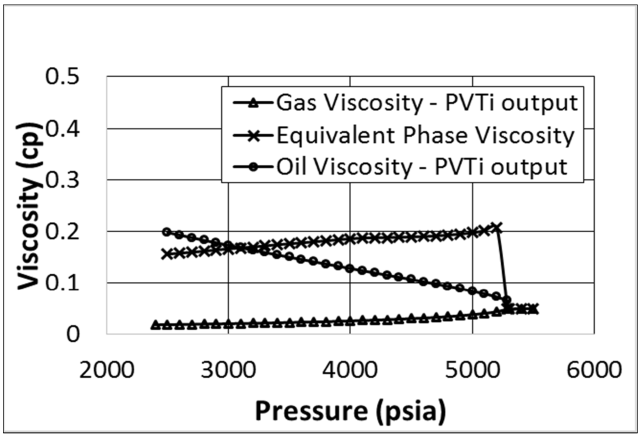

Fig. 4: Viscosity Computations – Rich Fluid, RC1b k_r Curves.

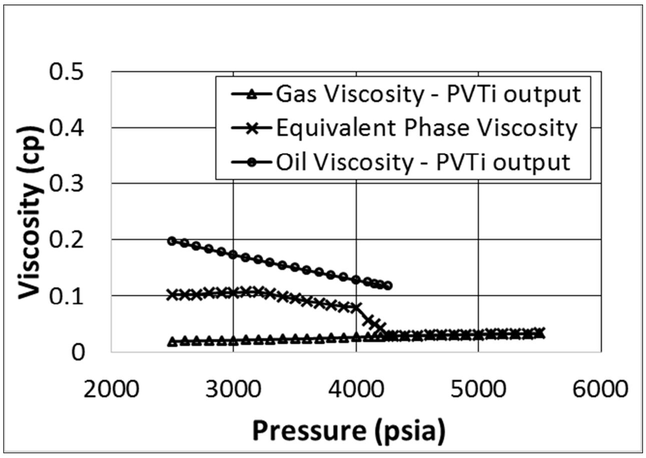

Fig. 5: Viscosity Computations – Lean Fluid, TC k_r Curves.

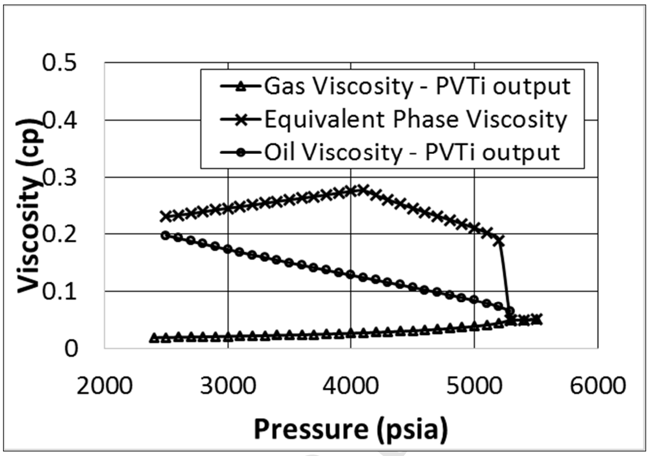

Fig. 6: Viscosity Computations – Rich Fluid, TC k_r Curves.

3.3 Type Curve Matching (TCM) Procedure

The pressure normalized rate $(q/\Delta P)$, its integral $(q/\Delta P)_i$, and its integral derivative $(q/\Delta P)_{id}$ are plotted together against the MBPT to produce what is referred to as the data plot, which is then superimposed on the type curves and shifted to obtain a match, taking care to ensure parallel axes and equal log cycle sizes on both plots. The TCM exercise produces a match-point (MP), the coordinates of which are read from the data plot and the type curves and used in the relevant equations (Palacio and Blasingame, 1993) to determine *k*, *s*, and r_e.

The TCM operations in this study were implemented in a spreadsheet software, to allow the flexibility needed to implement our pseudovariable modifications. To account for the total fluid volumes produced from the reservoir, the condensate production rates were converted to gas equivalent rates and added to the gas production rates. The production data was analysed using conventional type curve techniques, i.e. single-phase pseudopressure (1PSP) and single-phase material balance pseudotime (1MBPT), and then using Eq. 6 (2PSP) and Eq. 11 (2MBPT). The computation of the MBPT integral requires knowledge of $\bar{p}$ at each time step which, in this study, were taken from the simulation output.

4.0 Results and Discussion

Table 3 is a summary of TCM results for twenty cases obtained using single-phase and equivalent phase techniques. The pressure-saturation/k_r relations used for the two-phase analysis presented are based on the GTR approach described in Section 2.3.3. In Table 3:

- $S_{c,p_{wf}}\% = \frac{S_{c,p_{wf}}(GTR) - S_{c,p_{wf}}(SIM)}{S_{c,p_{wf}}(SIM)} * 100$: is used as an indicator of how closely the predicted condensate saturations match the simulated values during the transient flow period. $S_{c,p_{wf}}(GTR)$ is the condensate saturation at the given p_{wf} obtained from the GTR pressure-saturation prediction, and $S_{c,p_{wf}}(SIM)$ is the condensate saturation observed in simulation blocks nearest to the wellbore, during transient flow, with block pressure at p_{wf}.
- t_{2phase} (days): time at which the entire reservoir becomes two-phase.
- t_{BDF} (days): time at which stable boundary dominated flow (BDF) is established. It should be noted that stable BDF, as used here, is a time well after the "time of arrival" of the pressure disturbance at the external boundary.

We now discuss selected cases from this table.

Table 3: Summary of simulation cases analysed using Blasingame type curves.

	Fluid	k_r	Pi (psia)	Pwf (psia)	Error $S_{c,p_{wf}}\%$	t_{2phase} (days)	t_{BDF} (days)	MP 1-Phase ($q_{dD}=t_{dD}=0.1$)	1PSP, 1MPBT	MP 2-Phase ($q_{dD}=t_{dD}=0.1$)	2PSP, 2MBPT
1	V. Lean 98/2	RC1b	5,500	2,000	-	2621	2120	r_{eD}=20 q/Δp=0.11 t_{ca}=60	k=0.105 r_e= 1,236 S=-5.17	-	-
2	V. Lean 98-2	TC	5,500	2,000	-	2333	1861	r_{eD}=20 q/Δp=0.11 t_{ca}=60	k=0.105 r_e=1,236 S=-5.17	-	-
3	Lean (95/5)	RC1b	5,500	2,500	0.3%	873	4947	r_{eD}=19 q/Δp=0.05 t_{ca}=114	k=0.056 r_e=1,204 S=-5.20	r_{eD}=17 q/Δp=0.1 t_{ca}=60	k=0.108 r_e=1,241 S=-5.34
4	Lean (95/5)	RC1b	4,260	4,000	173.0%	31	2105	r_{eD}=20 q/Δp=0.09 t_{ca}=80	k=0.105 r_e=1,205 S=-5.15	r_{eD}=18 q/Δp=0.28 t_{ca}=29	k=0.313 r_e=1,235 S= -5.28
5	Lean (95/5)	RC1b	5,500	4,000	2%	1633	1740	r_{eD}=20 q/Δp=0.09 t_{ca}=64	k=0.104 r_e=1,210 s=-5.15	r_{eD}=20 q/Δp=0.09 t_{ca}=64	k=0.104 r_e=1,216 S=-5.16
6	Lean (95/5)	TC	4,260	2,500	80.0%	0.05	2348	r_{eD}=20 q/Δp=0.09 t_{ca}=80	k=0.105 r_e=1,205 S=-5.15	r_{eD}=15 q/Δp=0.37 t_{ca}=23	k=0.382 r_e=1,266 S=-5.49
7	Rich (88.5/11.5)	RC1b	5,289	2,500	1.6%	41	11377	r_{eD}=18 q/Δp=0.0095 t_{ca}=440	k=0.016 r_e=1,171 S=-5.22	r_{eD}=9 q/Δp=0.077 t_{ca}=70	k=0.090 r_e=1,243 S=-5.98
8	Rich (88.5/11.5)	RC1b	5,500	2,500	0.5%	337	11346	r_{eD}=18 q/Δp=0.01 t_{ca}=410	k=0.017 r_e=1,174 S=-5.23	r_{eD}=10 q/Δp=0.086 t_{ca}=52	k=0.108 r_e=1,227 S=-5.86

9	Rich (88.5/11.5)	RC1b	5,289	4,000	2.7%	44	10191	reD=20 q/Δp=0.11 tca=400	k=0.019 r_e=1,201 S=-5.14	r_{eD}=10 q/Δp=0.08 t_{ca}=72	k=0.101 r_e=1,283 S=-5.90
10	Rich (88.5/11.5)	RC1b	5,500	4,000	2.3%	469	10039	reD=18 q/Δp=0.013 tca=350	k=0.022 r_e=1,237 S=-5.28	r_{eD}=10 q/Δp=0.08 t_{ca}=60	k=0.100 r_e=1,272 S=-5.90
11	Rich (88.5/11.5)	RC1b	7,000	4,000	0.0%	1253	1223, 8261	r_{eD}=20 q/Δp=0.04 t_{ca}=50	k=0.072 r_e=945 S=-4.90	r_{eD}=20 q/Δp=0.061 t_{ca}=53	k=0.110 r_e=1,201 S=-5.15
12	Rich (88.5/11.5)	RC1b	10,000	4,000	0.0%	1633	1132, 4932	r_{eD}=20 q/Δp=0.048 t_{ca}=35	k=0.093 r_e=1,069 S=-5.03	r_{eD}=20 q/Δp=0.055 t_{ca}=38	k=0.107 r_e=1,193 S=-5.14
13	Rich (88.5/11.5)	RC1b	12,000	4,000	0.0%	1740	980, 3579	r_{eD}=20 q/Δp=0.05 t_{ca}=30	k=0.102 r_e=1,108 S=-5.06	r_{eD}=20 q/Δp=0.055 t_{ca}=30	k=0.112 r_e=1,162 S=-5.11
14	Rich (88.5/11.5)	RC1b	10,000	5,000	3.0%	2439	1071	r_{eD}=20 q/Δp=0.055 t_{ca}=38	k=0.107 r_e=1,193 S=-5.14	r_{eD}=20 q/Δp=0.055 t_{ca}=39	k=0.107 r_e=1,208 S=-5.15
15	Rich (88.5/11.5)	TC	5,289	2,500	16.3%	24	3366	r_{eD}=15 q/Δp=0.032 t_{ca}=130	k=0.049 r_e=1,169 S=-5.41	r_{eD}=10 q/Δp=0.5 t_{ca}=12	k=0.623 r_e=1,270 S=-5.89
16	Rich (88.5/11.5)	TC	5,289	5,000	50.6%	36	2226	r_{eD}=20 q/Δp=0.052 t_{ca}=90	k=0.090 r_e=1,238 s=-5.18	r_{eD}=18 q/Δp=0.22 t_{ca}=48	k=0.363 r_e=1,680 S=-5.59
17	Rich (88.5/11.5)	TC	10,000	5,000	-6.1%	2059	1101	r_{eD}=20 q/Δp=0.055 t_{ca}=38	k=0.107 r_e=1,193 S=-5.14	r_{eD}=20 q/Δp=0.055 t_{ca}=40	k=0.107 r_e=1,224 S=-5.16
18	Very Rich (86.5/13.5)	RC1b	6,000	4,000	-7.1%	935	11753	reD=20 q/Δp=0.035 tca=110	k=0.049 r_e=1,044 S=-5.00	r_{eD}=20 q/Δp=0.08 t_{ca}=65	k=0.111 r_e=1,222 S=-5.16
19	Rich (88.5/11.5)	RC1b Mod	5,284	2,500	-20.7%	35	7561	r_{eD}=20 q/Δp=0.018 t_{ca}=240	k=0.031 r_e=1,190 S=-5.14	r_{eD}=10 q/Δp=0.06 t_{ca}=90	k=0.075 r_e=1,205 S=-5.84
20	Rich 88.5/11.5	RC1b Mod	10,000	2,500	-7.2%	934	4886	r_{eD}=20 q/Δp=0.04 t_{ca}=42	k=0.078 r_e=1,069 S=-5.02	r_{eD}=20 q/Δp=0.057 t_{ca}=37	k=0.111 r_e=1,224 S=-5.16

4.1 Impact of Two-phase Conditions on the Shape of the Production Profile.

Fraim and Wattenbarger (1988), in their work which focused on solution-gas drive reservoirs, noted a "small step" in the decline curve at the beginning of BDF, which was attributed to the decreasing ratio of total mobility to total compressibility as the pressures in the reservoir approached the bubble point pressure, p_b.

They suggested that the magnitude of this step (which disappears when the initial reservoir pressure, p_i, is equal to p_b, is directly proportional to the difference between the p_i and p_b (i.e. the degree of undersaturation). This study found similar observations, with regards to the presence of a "small step" in the decline curve, to be true for gas condensate reservoirs (GCR). These are discussed next.

The production profiles for each of the cases simulated were first examined on rate-time log-log plots. Fig. 7 shows a rate-time log-log plot, comparing the gas production rates for four cases (Cases 10, 11, 12 and 13), all of which employ the rich fluid (MLDO = 28.01%). For these cases, p_{wf} is constant at 4,000 psia, while p_i ranges from 5,500 psia to 12,000 psia from Case 10 to 13.

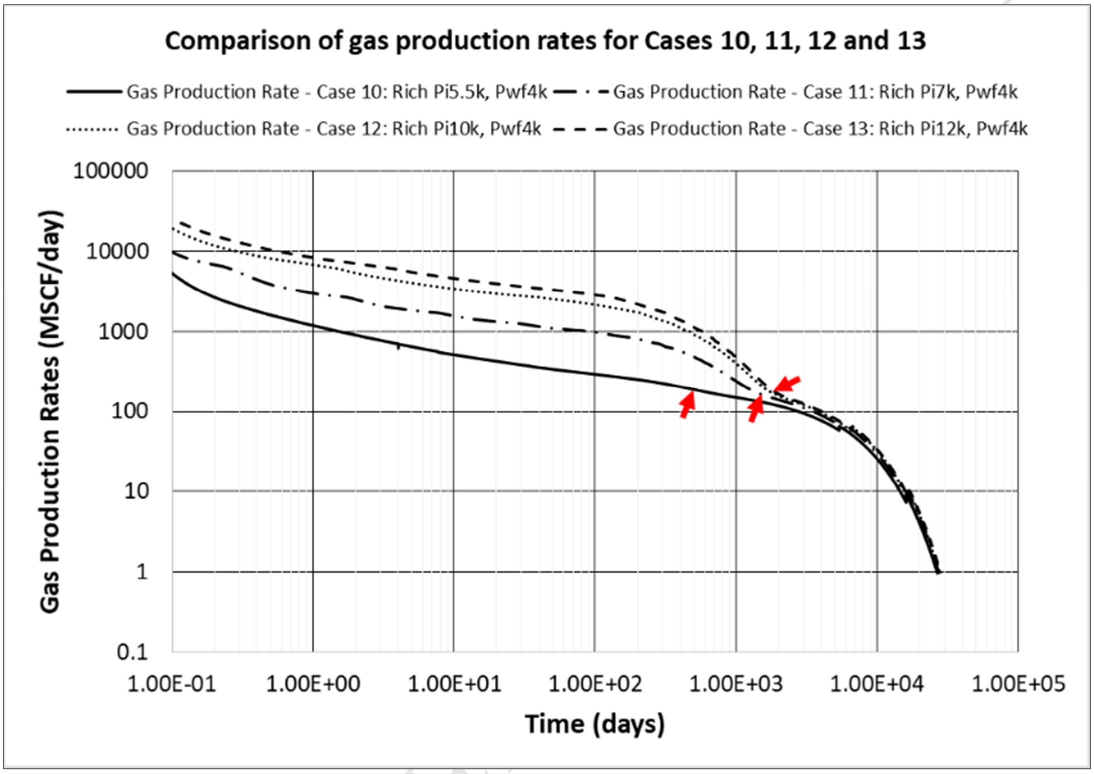

Fig. 7: Log-log plot of gas production rates for simulation cases 10, 11, 12 and 13. The arrows in this figure indicate the point in time at which two-phase conditions are established in the entire reservoir.

For Case 10, the least undersaturated case, the entire reservoir becomes two phase at the point indicated by the arrow (in Fig. 7), which is before stabilized BDF is established. For this case, there is almost no visible discontinuity on the curve. However, for Cases 11, 12, and 13 there is a clear kink in the production profile at a time when two-phase conditions are established in the entire reservoir. This kink occurs later in time and becomes more prominent as the degree of undersaturation increases. Similar plots for the very lean fluid cases (Cases 1 and 2) and lean fluid cases (Cases 3 and 5) did not show such noticeable kinks.

It was also noted that while these kinks were observed for cases using the RC1b k_r curves, they were less evident for analogous cases using the TC k_r curves. A significant difference between these two k_r curves is seen in the behaviour of k_{rg}. As condensate saturation increases beyond zero, the RC1b k_r curves show a sharply declining k_{rg}, while the TC k_r curves show a less drastic decrease in k_{rg}. In other words, total mobility is initially not as adversely affected for TC as for RC1b cases. The trend in k_{rg} is of particular importance, because initial k_{ro} values are typically low. The observations from this study showed that the kink is most prominent for cases involving rich fluids, at high degrees of undersaturation, and with k_r curves which exhibit sharply decreasing k_{rg} at the onset of two-phase conditions.

Another important impact of two-phase effects on the shape of the decline curve, which was seen for some cases, e.g. Case 15, was an observed steepening of the transient stem, as mentioned by Sarisittitham and Jamiolahmady (2014). This is attributed to increasing total skin with the growth of the condensate bank, and also has the potential to impact the quality of type curve analysis, to which we now turn our attention.

4.2 PDTC Analysis of Simulated Cases

The results of the conventional type curve analysis are shown in columns 9 and 10 of Table 3, and the equivalent phase based type curve analysis, in columns 11 and 12. For equivalent phase based analysis, the saturations and k_r used to compute Eq. 6 and Eq.11 were predicted using the GTR approach, described in Section 2.3.3, which is based on near-wellbore two-phase steady state assumptions. In our studies, this near wellbore region was found to be within 10% of the drainage radius (i.e. the reservoir radius, for the single-well cases considered in this study).

Under two-phase steady state conditions, the constant bottomhole pressure production constraint assumed in this study would correspond to a unique "steady state" saturation value at the sandface. Upstream regions/blocks will be at higher pressures and hence different saturations. However, as long as the two-phase steady state assumptions are valid in the near wellbore region, the condensate saturation corresponding to any given pressure (below p_{dew}) at any point in that region would match the predicted condensate saturation.

Here, a pseudopressure integral, which accounts for changes in saturation and k_r with radial distance from the wellbore, i.e. the reservoir integral presented by (Jones and Raghavan, 1988), would be most applicable. However, for practical applications, the sandface pseudopressure integral computed on the basis of the steady state theory (i.e. Eq.4) was shown by (Jones and Raghavan, 1988) to produce good estimates of flow capacity (*kh*), during transient flow even for constant pressure production. This pseudopressure integral is employed in our study which involves the analysis of long-term production data for which both transient and boundary dominated flow regimes are present.

4.2.1 Very Lean Gas Condensate Systems – Single-phase Analysis

The Blasingame type curve match (TCM) results for Case 1 (with MLDO of 0.86%), shown in Fig. 8, indicates that the parameter estimates obtained using single-phase pseudovariables agree well with the model input parameters. For this case, two-phase effects were not significant enough to impact the results obtained using the single-phase techniques. It is also worth noting that for this case t_{2phase} was found to be greater than t_{BDF}, and there was no prominent kink. Similar results were obtained for Case 2.

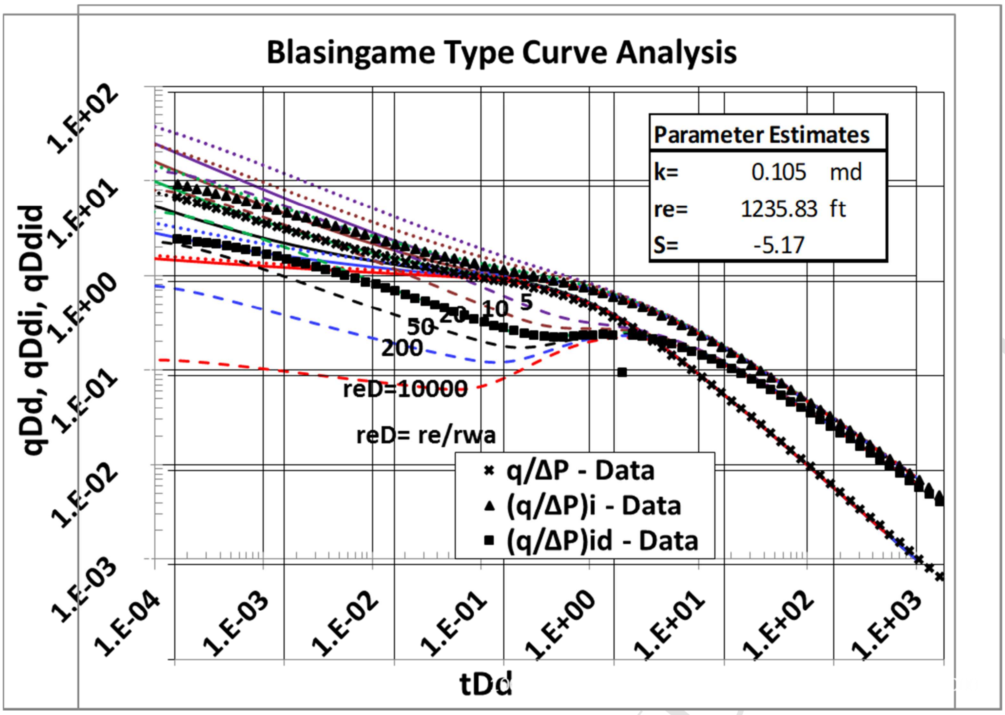

Fig. 8: Blasingame TCM single-phase analysis for Case 1 (simulation inputs: k =0.1 md, r_e = 1242 ft, s = -5.16, p_i = 5,500 psia, p_{wf} = 2,000 psia, RC1b k_r curves, very lean fluid with p_{dew}=2,441 psia and CCE maximum liquid dropout= 0.86%).

For subsequent cases employing progressively richer fluids (MLDO of 7% to 42%), the impact of two-phase effects on the parameter estimates obtained using single-phase analysis became more evident, producing lower permeability estimates. Such trends would be consistent with the fact that the use of single-phase techniques assumes that the primary phase (which in this case is gas) is the only mobile phase. Significant errors in parameter estimates resulting from the use of single-phase PDTC techniques under two-phase conditions in GCRs have been well documented in literature (Sarisittitham and Jamiolahmady, 2014). If the objective for analysing such data is to determine the absolute permeability of the reservoir, then the use of single-phase techniques alone would produce unsatisfactory results. Single-phase and two-phase analysis (based on the equivalent phase concept) for selected cases (from Table 3) with increasing fluid richness are now examined, beginning with undersaturated cases.

4.2.2 Case 3: Lean Fluid, P_i = 5,500 psia, P_{wf} = 2,500 psia

This case employs the lean fluid (MLDO = 7.39%). The single-phase analysis of this case showed a 44% reduction in the k estimate. The use of two-phase pseudopressures and the equivalent phase MBPT produced parameter estimates consistent with the model inputs, as can be seen in Table 3.

4.2.3 Case 5: Lean Fluid, P_i = 5,500 psia, P_{wf} = 4,000 psia

For this case, the impact of two-phase effects was far less significant compared to Case 3. The single phase analysis of this case produced reliable estimates of k, r_e and s. This can be attributed to the higher p_{wf}, and the associated lower condensate saturations around the wellbore as well as the more delayed onset of two-phase effects in the entire drainage volume. The two-phase analysis of this case again gave parameter estimates which were very consistent with the model inputs.

4.2.4 Case 8: Rich Fluid, P_i = 5,500 psia, P_{wf} = 2,500 psia

The only difference between this case and Case 3 is the change of the fluid richness. Here, single-phase analysis resulted in a permeability estimate that was 83% less than the absolute permeability simulation input. Two-phase analysis produced a k estimate consistent with the simulation input, r_e estimate within 2% of the input, and s estimate within 0.7 units of the mechanical skin. Case 10 (rich fluid MLDO = 28.01%, p_i = 5,500, p_{wf} = 4,000 psia), produced very similar results. For these two cases, the entire reservoir became two-phase long before stabilized BDF was established, as can be seen by comparing t_{2phase} with t_{BDF} for each case.

4.2.5 Case 11: Rich Fluid, P_i = 7,000 psia, P_{wf} = 4,000 psia

The single-phase analysis for Case 11, which has a higher degree of undersaturation compared to Case 10, is shown in Fig.9. Here a deviation in the harmonic decline stem during BDF, corresponding to the kink discussed in Section 4.1, is evident on the data plot. For this case, this event occurs right at the onset of stabilized BDF (i.e. just after the transition).

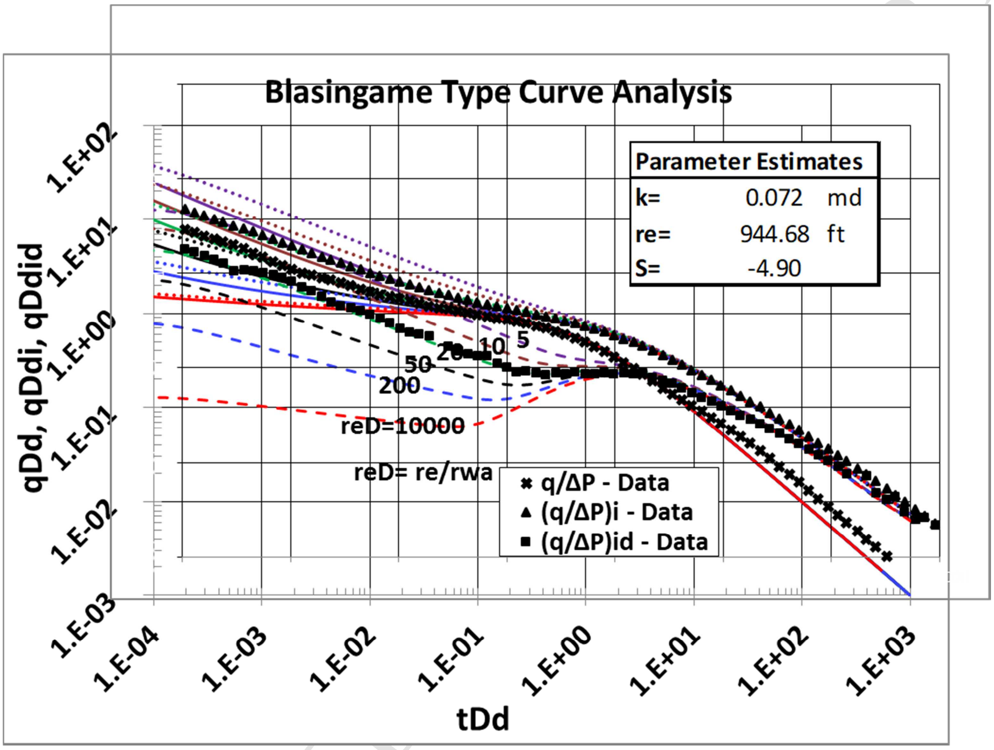

Fig. 9: Blasingame TCM single-phase analysis for Case 11 (simulation inputs: k =0.1 md, r_e = 1200 ft, s = -5.16, p_i = 7,000 psia, p_{wf} = 4,000 psia, RC1b k_r curves, rich fluid with p_{dew}=5,289 psia and CCE maximum liquid dropout= 28.01%).

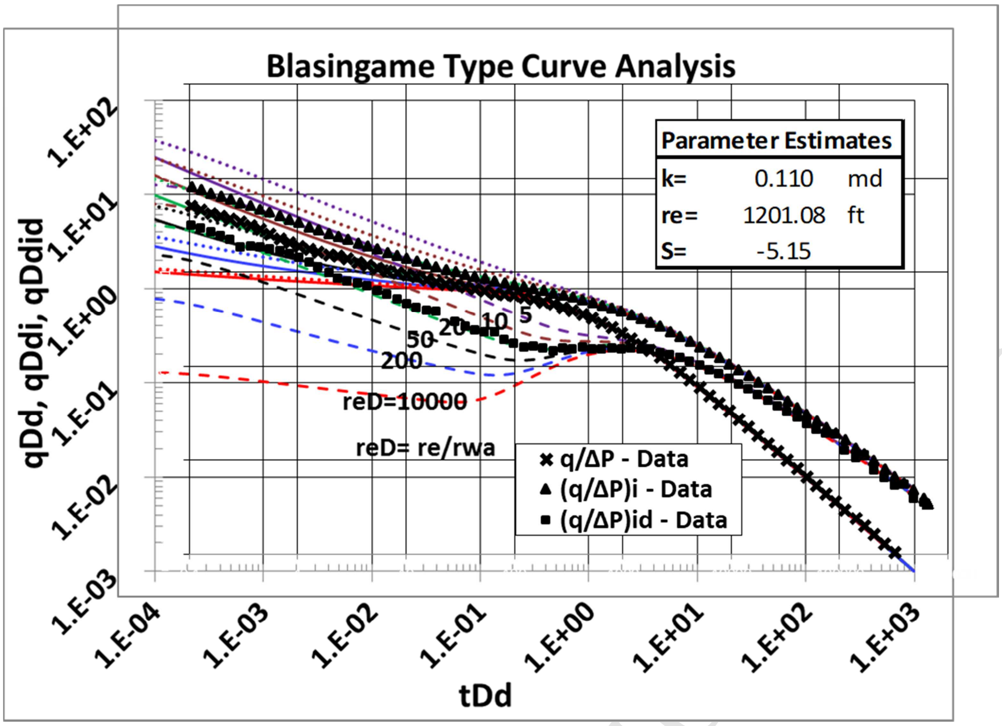

Fig. 10: Blasingame TCM two-phase analysis for Case 11 (simulation inputs: k =0.1 md, r_e = 1200 ft, s = -5.17, p_i = 7,000 psia, p_{wf} = 4,000 psia, RC1b k_r curves, rich fluid with p_{dew}=5,289 psia and CCE maximum liquid dropout= 28.01%).

This deviation in the harmonic decline stem creates some uncertainty in the TCM, which is found to be most significant when it occurs closer to the beginning of stable BDF, than when it occurs much later. It is also worth noting that the decline stem after the deviation, still preserves the harmonic trend (i.e. a negative unit slope), and that such deviations in the harmonic decline stem are not unique to two-phase effects, as similar deviations were observed for multi-well interference effects (Marhaendrajana and Blasingame, 2001).

Examining the parameter estimates obtained using single-phase techniques for Case 11, it is observed that the type curve match produces permeability estimates that are significantly less underestimated (i.e. error of -27%) than Cases 10.

The two-phase analysis of the same case is shown in Fig. 10 where, with the use of the equivalent-phase MBPT, the deviation in the harmonic stem is resolved, resulting in a much more confident TCM, and improved parameter estimates.

Cases 12 and 13, as well as Case 20, which employed the very rich fluid (MLDO 42%), showed trends similar to those seen for Case 11, i.e. for the same p_{wf}, with increasing degree of undersaturation, single-phase analysis produced permeability estimates that were progressively closer to the absolute permeability, and the use of the equivalent phase MBPT resolved the deviation in the harmonic stem, where present. For severely undersaturated cases where this deviation in the harmonic decline stem was either absent or less prominent e.g. for cases 14 and 17 (for the reasons discussed in Section 4.1), the use of the equivalent phase MBPT was not so critical, although its use still gave accurate results. It is worth noting that for these severely undersaturated cases, the steepening of the transient stem due to increasing total skin, as mentioned in Section 4.1, was less significant.

As already mentioned, for cases where the entire reservoir becomes two-phase during transient flow, the discontinuity/kink in the production profile is not very evident on the log-log rate-time plot. For such cases however, the rate integral derivative curve $(q/\Delta P)_{id}$, which is most sensitive to changes, exhibits a disturbance which can negatively impact the quality of the TCM (e.g. Cases 8 and 10).

The saturated reservoir scenarios presented in Table 3 are cases 4, 6, 7, 9, 15, 16, and 19. Single-phase analysis of some of these cases, namely cases 4, 6, and 16, produced good k estimates. The two-phase analysis of these cases are examined in detail in Section 4.2.7.

In general, our results indicate that for a gas condensate reservoir, operating with $p_{wf} < p_{dew}$ the extent to which permeability estimates from single-phase analysis are impacted by two-phase effects is dependent not only on the condensate saturation levels that occur around the wellbore during the transient flow regime, but also on the timing of the point at which the entire drainage volume becomes two-phase.

For cases like 1, 2, 4, 5, 6, and 16, single-phase analysis produced k estimates consistent with the input because the average condensate saturations in the two-phase region during transient flow did not exceed levels for which k_{rg} dropped below 0.7-0.8. Generally, for cases where the average condensate saturation exceeded such levels, the k estimate began to reduce significantly (i.e. more than 10% underestimation). However if, for such cases, the onset of two-phase conditions in the entire reservoir was delayed (due to higher degrees of undersaturation), then once again single-phase analysis began to produce reasonably good estimates of *k*, e.g. cases 12, 13, 14, and 17.

4.2.6 Undersaturated Cases: Use of Two-Phase Steady State Pressure-Saturation

For cases 3, 5, 8, 10, 11, 12, 13, 14, 17, 18, and 20, two phase analysis using the GTR based pressure-saturation relations produced parameter estimates consistent with the model inputs. As can be seen from Table 3, these were cases for which the S_{cpwf}% was within ±10%. As mentioned earlier, S_{cpwf}% is a computed measure of the closeness of the predicted saturation at the wellbore to those observed in the simulation models. These cases for which the use of two-phase steady state pressure-saturation prediction produced good results were generally those for which p_i-p_{dew} was sufficiently high, which agrees with trends suggested in literature (Fussell, 1973, Raghavan et al., 1999). In other words, for higher degrees of undersaturation, the predicted pressure-saturation response matched more closely with those in the simulation, because such conditions honoured the two-phase steady state constant composition assumptions.

It is interesting to note that for initially undersaturated reservoirs, two-phase steady state based pseudovariables produce reliable type curve matches and parameter estimates, even though the two-phase steady state constant composition assumption is violated at some point in the production period (i.e. when $\bar{p}$ falls below p_{dew}). These results suggest that even though two-phase steady state theory does not adequately capture the pressure-saturation response during BDF (with $\bar{p} < p_{dew}$), it is adequate for the purpose of estimating kh and r_e and s from long-term production data affected by two-phase flow, as long as it adequately captures the pressure-saturation response around the wellbore during transient flow for constant pressure production. This is a useful observation, given that two-phase steady state pressure-saturation responses like the one employed in this study are particularly attractive because they are simple to compute if k_r data and fluid PVT data are available as described in Section 2.3.3.

4.2.7 Saturated Cases: Use of Two-Phase Steady State Pressure-Saturation

For saturated cases like Case 4, Case 6, Case 15, Case 16 and Case 19, the use of two-phase steady state pressure-saturation/k_r in the two-phase analysis generally did not produce reliable parameter estimates. From Table 3, it can be seen that for these cases, the predicted pressure-saturation responses were not sufficiently representative of the actual responses, as evidenced by the S_{cpwf} %. For cases 4, 6, 15, and 16, two-phase analysis produced an overestimated k. This occurs because for these cases, the two-phase steady state based approach overestimates the condensate saturations around the wellbore. Under such conditions, the two-phase pseudopressure integral, Eq. 4, tends to be lower than it should be, with the result that the absolute k from two-phase analysis is overestimated.

Similarly, under such conditions, the equivalent phase MBPT integral is much lower than it ought to be, impacting the TCM on the time axis, and making the r_e estimate less reliable. In such cases, r_e could be overestimated to varying degrees, and in some cases might be less affected, because the TCM equation for estimating r_e includes the k estimate (Palacio and Blasingame, 1993).

For Case 19, which employed the k_r curves with enhanced k_{ro} (shown in Fig. 1), the use of the two-phase steady state methods gave condensate saturations which were lower than the actual values occurring around the wellbore, as evidenced by the very negative S_{cpwf} %. For this case, the two-phase analysis produced underestimated k. This scenario might be associated with rocks which exhibit high k_{ro}.

Cases 7 and 9, which are both saturated reservoir cases, are exceptions to the observed trends for saturated cases, because for these cases, owing to the particular combination of fluid richness and k_r curves, the condensate saturation levels around the wellbore were found to be relatively independent of the degree of undersaturation.

It is useful to note from the two-phase analysis results of these saturated cases, that the extent of overestimation or underestimation in the absolute k is not necessarily directly proportional to S_{cpwf} %, as the overall impact is dependent on the k_r characteristics.

Clearly, for saturated cases, the use of the two-phase steady state pressure-saturation response in the data analysis generally produced less satisfactory results. For such cases, the use of other sources of pressure-saturation/k_r data, such as CCE curves, together with the equivalent phase concept, is examined and to be presented in subsequent studies.

5.0 Conclusions

This study examined production data analysis using type curves (PDTC) in gas condensate reservoirs operating at constant well flowing pressure (p_{wf}) below dewpoint pressure (p_{dew}). Varying degrees of reservoir undersaturation, different gas condensate fluid richness and relative permeability curves were considered, highlighting their impact on the equivalent phase approach to two-phase PDTC analysis. Using simulated production data, the results demonstrated that:

– The severity of the impact of two-phase effects on the quality of type curve match (TCM) and parameter estimates was dependent on condensate saturation levels occurring around the wellbore as well as the point at which the entire reservoir became two-phase (which depended on the degree of undersaturation).

– Two-phase analysis using a combination of two-phase pseudopressures and a material balance pseudotime (MBPT) integral computed using equivalent phase fluid properties produced good TCMs and accurate parameter estimates, as long as sufficiently representative pressure-saturation responses were employed. In this study, where two-phase steady state based pressure saturation predictions were employed, good results were obtained when S_{cpwf}% (i.e. a computed measure of the closeness of predicted saturations to actual saturations in the simulation during the transient flow period) was within ±10%.

- For initially undersaturated reservoirs, even though two-phase steady state theory does not adequately capture the pressure-saturation response in the reservoir during boundary dominated flow (BDF), with $\bar{p} < p_{dew}$, it proved adequate for the computation of two-phase pseudovariables for estimating *kh*, r_e and *s*, from long-term production data. This is valid, when using PDTC, and as long as such pressure-saturation predictions are sufficiently representative of the actual response around the wellbore during the transient flow regime.

At higher degrees of undersaturation (i.e. $p_i >> p_{dew}$):

- Two-phase steady state pressure-saturation predictions became more representative, and therefore produced more reliable two-phase analysis results.
- If sufficient stabilized BDF was attained before the entire reservoir became two phase (with a resultant discontinuity/kink in the decline curve), then a reasonable TCM might still be obtained with relatively reliable parameter estimates using single-phase analysis. However, deviations in the harmonic decline stem resulting from the presence of the kink could make the TCMs less certain, impacting the quality of r_e and *s* estimates. The use of the equivalent phase MBPT resolved such deviations, producing more confident TCM and parameter estimates.

At low degrees of undersaturation (i.e. $p_i \approx p_{dew}$):

- Two-phase conditions were established in the entire reservoir before stable BDF, and the impact of two-phase effects on the decline curve appeared to be most significant, particularly for the rich fluids, producing lower *k* estimates from single-phase analysis.

– The use of two-phase steady state pressure-saturation/k_r in the two-phase analysis of such cases could overpredict or underpredict the saturations that actually occurred around the wellbore, causing overestimated or underestimated absolute k, and less reliable r_e estimates. For such cases, the use of alternative sources of pressure-saturation data, together with our equivalent phase approach ought to be explored. This is the subject of our subsequent studies to be presented in future papers.

Nomenclature

A	= area, ft^2
B	= formation volume factor, RB/MSCF
b	= Arps decline factor, dimensionless
$b_{a,pss}$	= pseudosteady state flow constant, dimensionless
c_{tot}	= saturation weighted total compressibility, psi^{-1}
C_A	= reservoir shape factor
c	= compressibility, psi^{-1}
D_i	= Arps initial decline rate, day^{-1}
h	= producing interval thickness, ft
J_0	= zero order Bessel function of the first kind
J_1	= first order Bessel function of the first kind
k	= effective permeability, md
k_r	= relative permeability, dimensionless
L	= liquid mole fraction (CCE experiments)
$m(p)$	= real gas pseudopressure, psi^2/cp
m_a	= a constant in Eq. 8
$\bar{p}$	= average reservoir pressure, psi
p	= pressure, psi.
p^*	= pressure at the outer boundary of region 1, in Eq. 5, psia
p_{dew}	= dewpoint pressure, psia
p_{wf}	= well flowing pressure, psia
Q	= volumetric flow rate for gas or oil
Q_m	= cumulative liquid production at time t, variable-rate case, STB/day
q	= surface production rate at time t, MSCF/day
q_m	= liquid flow rate at time t, variable-rate case, STB/day
R_s	= solution gas oil ratio, scf/STB
R_p	= producing gas oil ratio, scf/STB
R_v	= solution oil gas ratio, STB/scf
r_e	= external reservoir radius, ft
r_w	= wellbore radius, ft
r_{wa}	= effective wellbore radius, ft
S	= saturation
S_{wi}	= irreducible water saturation in Eq. 5

s = near well true skin factor, dimensionless
$\bar{t}$ = material balance time, days
$\bar{t}_a$ = material balance pseudotime (MBPT), days
$t_{a,tp}$ = real gas condensate pseudotime, days
$\bar{t}_{a,tp}$ = equivalent phase MBPT, days
V = vapour mole fraction (CCE experiments)
V_o = oil volume fraction (CCE experiments)
V_g = vapour volume fraction (CCE experiments)
X_n = root of 1st order Bessel function of the first kind
x_j = weight fraction of jth component in condensate phase
y_j = weight fraction of jth component in gas phase
z_j = weight fraction of jth component in reservoir fluid
z = compressibility factor
$\frac{dP}{dL}$ = pressure gradient, psi/ft
Δp_p = pseudopressure drop, psi.
γ = 0.577216, Euler's constant
μ = viscosity, cp
$\mu_{eqphase}$ = equivalent phase viscosity, cp
ρ = fluid density, lbm/ft
$\emptyset$ = porosity

Subscripts

dg = dry gas
g = gas
i = initial
l = liquid
o = oil (condensate)
t = total
tp = two-phase
w = water

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Highlights:

- Use of single-phase decline type curves for gas condensate analysis can be unreliable
- Significant two-phase impacts are seen in saturated rich gas condensate reservoirs
- Two-phase impacts are less significant at higher degrees of reservoir undersaturation
- An equivalent phase approach to two-phase decline type curve analysis is introduced
- The equivalent phase method improves two-phase decline type curve analysis